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**STATE OF NEW MEXICO**
**BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD**

**IN THE MATTER OF:**

**PROPOSED NEW REGULATION** **No. EIB 21-27 (R)**
***20.2.50 Oil and Gas Sector – Ozone Precursor Pollutants***
**Hearing Date: September 20, 2021**

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**NOTICE OF INTENT TO PRESENT REBUTTAL TECHNICAL TESTIMONY OF KINDER MORGAN, INC. AND ITS SUBSIDIARIES AND AFFILIATES, EL PASO NATURAL GAS COMPANY, L.L.C., TRANSCOLORADO GAS TRANSMISSION CO., LLC, AND NATURAL GAS PIPELINE COMPANY OF AMERICA, LLC**

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Kinder Morgan, Inc. and its subsidiaries and affiliates, El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC (collectively, "Kinder Morgan") submit to the Environmental Improvement Board (the "Board") this notice of intent to present rebuttal technical testimony at the public hearing in the above-captioned matter pursuant to 20.1.1.302.B. NMAC (the "Rebuttal Notice").

1. **Entity for whom the witnesses will testify**: Kinder Morgan.

2. **Identity of witnesses**: Kinder Morgan will call the following witnesses at the hearing to present rebuttal technical testimony: (1) Leslie R. Nolting, Air Permitting and Compliance Manager for Kinder Morgan, (2) Vincent L. Brindley, Technical Supervisor for Kinder Morgan, and (3) James R. Trent, Staff Engineer for Kinder Morgan. A copy of Ms. Nolting's resume is attached as Exhibit I to the Notice of Intent to Present Technical Testimony of Kinder Morgan, Inc. and Its Subsidiaries and Affiliates, El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC filed on July 28, 2021 ("Kinder Morgan's Direct Technical Testimony"). A copy of Mr. Brindley's resume is attached as Exhibit II to Kinder Morgan's Direct Technical Testimony. A copy of Mr.

Trent's resume is attached as Exhibit III to Kinder Morgan's Direct Technical Testimony. The witness qualifications of each of Ms. Nolting, Mr. Brindley, and Mr. Trent are described in Exhibit IV to Kinder Morgan's Direct Technical Testimony.

We summarize in Table 1, below, the assignment of rebuttal technical testimony to be provided by Ms. Nolting, Mr. Brindley, and Mr. Trent by section of 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants (the "Proposed Rules"), and the anticipated duration of such testimony. As indicated in the far left column of Table 1, the relevant narrative technical testimony is provided in an exhibit to this Rebuttal Notice.

**Table 1: Assignment of Rebuttal Technical Testimony**

| Exhibit | Rule Section | Topic | Direct Testimony Witness(es) | Anticipated Duration of Testimony | Additional Witnesses[1] |
|---|---|---|---|---|---|
| **Exhibit XI** | Section 7 | Definitions | Leslie Nolting | 10 minutes | Vincent Brindley<br>James Trent |
| **Exhibit XII** | Section 112 | General Provisions | Leslie Nolting | 5 minutes | Vincent Brindley<br>James Trent |
| **Exhibit XIII** | Section 113 | Engines and Turbines | James Trent | 30 minutes | Leslie Nolting<br>Vincent Brindley |
| **Exhibit XIV** | Section 114 | Compressor Seals | Vincent Brindley | 15 minutes | Leslie Nolting<br>James Trent |
| **Exhibit XV** | Section 116 | Equipment Leaks and Fugitive Emissions | Leslie Nolting | 10 minutes | Vincent Brindley<br>James Trent |
| **Exhibit XVI** | Section 121 | Pig Launching and Receiving | Vincent Brindley | 10 minutes | Leslie Nolting<br>James Trent |
| **Exhibit XVII** | Section 122 | Pneumatic Controllers and Pumps | Leslie Nolting | 5 minutes | Vincent Brindley<br>James Trent |
| Total Anticipated Duration of Rebuttal Testimony: | | | | 85 minutes | |

3. **List of Exhibits**: A list of the rebuttal exhibits that Kinder Morgan intends to offer into evidence in this matter is attached to this Rebuttal Notice. Kinder Morgan reserves the right

[1] Available for questions and cross-examination.

to introduce and move for admission of any other exhibit in support of additional rebuttal or direct testimony at the hearing.

4. **Incorporation of NMOGA Rebuttal Testimony**: To the extent consistent with this Rebuttal Notice, Kinder Morgan endorses, joins, and incorporates by reference the entirety of the rebuttal technical testimony of the New Mexico Oil and Gas Association ("NMOGA") filed in this matter (the "NMOGA Rebuttal Testimony"). For the avoidance of doubt, Kinder Morgan's incorporation by reference of the NMOGA Rebuttal Testimony includes all content, attachments, exhibits, citations, and documents associated with such testimony.

Respectfully submitted this 7th day of September, 2021.


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## EXHIBIT LIST

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|---|---|
| **Exhibit XI** | Section 7: Definitions |
| **Exhibit XII** | Section 112: General Provisions |
| **Exhibit XIII** | Section 113: Engines and Turbines |
| **Exhibit XIV** | Section 114: Compressor Seals |
| **Exhibit XV** | Section 116: Leak Detection and Repair |
| **Exhibit XVI** | Section 121: Pig Launching and Receiving |
| **Exhibit XVII** | Section 122: Pneumatic Controllers and Pumps |
| **Exhibit XVIII** | Proposed Redline[2] |

[2] This redline reflects Kinder Morgan's proposed changes to the version of the rule that the New Mexico Environment Department ("NMED") included as Exhibit 41 to its Notice of Intent to Present Technical Testimony. In our redline, we accepted NMED's proposed changes set out in Exhibit 41, and then provided our changes in track changes to that clean version of Exhibit 41.

**EXHIBIT XI**

**SECTION 7: DEFINITIONS**

**Q. Ms. Nolting, what are your reactions to the revised definitions of "gathering and boosting station" and "natural gas compressor station," and the new definition of "transmission compressor station" reflected in NMED's Notice of Intent to Present Direct Technical Testimony filed on July 28, 2021 ("NMED's NOI")?**

**A.** In its redline of the Proposed Rules, included as Exhibit 41 to NMED's NOI, NMED proposes the following revised definitions of "gathering and boosting station" and "natural gas compressor station":

> **Q. "Gathering and boosting station"** means a facility, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.~~means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage~~.

> **W. "Natural gas compressor station"** means ~~one or more compressors~~a facility, including all equipment and compressors, designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. Natural gas compressor stations include transmission compressor stations.

NMED also proposes a new defined term—"transmission compressor station"—as follows:

> **SS. "Transmission Compressor Station"** means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

I offer the following comments regarding these proposed definitions.

First, the definition of "natural gas compressor station" should be deleted. It is imprecise and over-broad, and it conflates the operations of gathering and boosting segment compressor stations with the operations of transmission segment compressor stations. The term "natural gas compressor station" encompasses both "gathering and boosting stations" and "transmission compressor stations." However, it is inaccurate to suggest that gathering and boosting operations and transmission operations are equivalent, particularly when considering the volatile organic compound ("VOC") emissions of the two sectors. These stations are located at different points along the natural gas supply chain, which fundamentally affects the VOC emissions profile of each type of station. In particular, the natural gas moved through transmission compressor stations has a much lower VOC content than the natural gas moved through gathering and boosting stations. Inevitably, this impacts the effectiveness, and cost-effectiveness, of the proposed emissions standards intended to reduce VOCs.

With refined definitions of "gathering and boosting station" and "transmission compressor station," a separate definition of "natural gas compressor station," which combines the two is not necessary. Any such combined definition is bound to create confusion and conflict. For example, in each applicability section of the Proposed Rules, NMED's most recent version of the Proposed Rules now lists both "gathering and boosting stations" and "natural gas compressor stations," and deletes "transmission compressor stations." *See, e.g.*, NMED's NOI, Ex. 41, at Section 113.A. This creates at least some confusion in that the gathering and boosting segment is specifically identified and also referenced through incorporation of the defined term "natural gas compressor station," but transmission is not independently identified apart from the reference to natural gas compressor stations.

Likewise, in Section 122 (Pneumatic Controllers and Pumps), Table 1 outlines the cohorts for total historic percentages of non-emitting controllers, which dictates the required percentages of non-emitting controllers year-over-year. Table 1 applies to well sites, tank batteries, and gathering and boosting stations. Table 2 outlines *different* cohorts with *different* required percentages for non-emitting controllers. Table 2 applies to natural gas compressor stations and gas processing plants. Under the current definitions, a gathering and boosting station is both a gathering and boosting station and a natural gas compressor station. Thus, it is unclear whether the operator of a gathering and boosting station should comply with Table 1 or Table 2 in Section 122.[3] In sum, it is unnecessary in these and other instances to refer to “natural gas compressor stations” if “transmission compressor station” is the intended term.

Additionally, I think it is important to note that NMED cites to Colorado’s Regulation No. 7, Part D, Section I.B.19 as a source for the definition of “natural gas compressor station.” *See* NMED’s NOI, Ex. 32, at 18. Colorado’s Regulation No. 7 does not support the NMED’s proposed definition of “natural gas compressor station,” although Regulation No. 7 includes a definition of this term. Rather, the cited section of Colorado Regulation No. 7 states: “‘Natural Gas Compressor Station’ means a facility, *located downstream of well production facilities*, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure *prior to the inlet of a natural gas processing plant*.” 5 CCR 1001-9:D.I.B.19 (emphases added). This definition is almost identical to NMED’s proposed definition of “gathering and boosting station,” which is the more appropriate application. Perhaps the most important distinction between Colorado’s use of “natural gas compressor station” and NMED’s use of “natural gas compressor station” is that Colorado’s definition *excludes* transmission compressor stations. In fact, Colorado does not regulate transmission compressor stations the same way that it regulates gathering and boosting compressor stations due, in part, to the low-VOC content of the pipeline quality natural gas transported by transmission operations. For the reasons

[3] While we refer the Board to this rule section by way of example, for the avoidance of doubt, Kinder Morgan re-iterates that we support NMOGA’s comments on Section 122 to revise the proposed rule to better conform with NMED’s intent to model Colorado’s rule, including excluding transmission compressor stations from rule application.

previously discussed in Kinder Morgan's Direct Technical Testimony, I continue to encourage NMED and the Board to clearly distinguish between compressor stations operated in the gathering and boosting segment from such stations operated in the transmission segment.

Second, we generally support the definition of "gathering and boosting station," but agree with the proposed clarifying edits offered by NMOGA, and shown on the redline attached as **Exhibit XVIII**.

Finally, we agree with NMED that a definition of "transmission compressor station," separate from a "gathering and boosting station," is appropriate, and we thank NMED for including this new definition. That said, we propose a number of clarifying edits to the definition of "transmission compressor station," which I summarize below. Further, as a global comment throughout the Proposed Rules, when intending to apply a particular rule section to transmission compressor stations, the rule should refer to "transmission compressor stations" and not "natural gas compressor stations," which we are proposing to delete. Kinder Morgan's proposed revision to each applicable rule section in this regard is shown on **Exhibit XVIII**.

As shown on **Exhibit XVIII**, hereto, we propose the following changes to the definition of "transmission compressor station":

- Addition of reference to "pipeline quality" natural gas. This is important because it is one of the key differentiating features between gathering and boosting and transmission.
- Reference to natural gas processing "plants" rather than "facilities" to conform to the defined term in the Proposed Rules.
- Reference to transmission "through" a pipeline rather than "in" a pipeline.

- Reference to delivery from transmission operations to the local distribution company custody transfer station (an NMED defined term, which may be a pipeline or may be a facility), into storage, or to other industrial users.
- Deletion of the list of equipment at the end of the definition. It is unnecessary to specify different types of equipment when "all equipment" is already referenced. Additionally, when read together with related definitions, listing specific equipment in the definition of "transmission compressor station" may imply that the listed types of equipment *are located* at transmission compressor stations and *are not located* at gathering and boosting stations or natural gas processing plants, which is inaccurate.

***Note****: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding these definitions.*

## EXHIBIT XII

## SECTION 112: GENERAL PROVISIONS

**Q. Ms. Nolting, do you have any reactions to NMED's testimony in Exhibit 32 to NMED's NOI related to Section 112 of the Proposed Rules?**

**A.** Yes. In its NOI, NMED states that the monthly inspection requirement set out in Section 112 "is the minimum periodic monitoring requirement for sources subject to Part 50 and requires owners and operators to evaluate the overall operation of the source." NMED's NOI, Ex. 32, at 28. Kinder Morgan does not believe that it is NMED's intention to override the plain language of Section 112, which requires monthly monitoring "unless a different schedule is specified in the Section applicable to that source type." NMED's NOI, Ex. 41, Section 112.B.(1). However, the statement in NMED's NOI regarding the monthly requirement as the "minimum" monitoring frequency required for sources subject to Part 50 creates confusion, and should be clarified or withdrawn.

We also note that NMED's redline (Exhibit 41 to its NOI) retains requirements related to Equipment Monitoring Tags ("EMTs"). Kinder Morgan supports all comments and revisions submitted by NMOGA regarding EMTs.

***Note***: *At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding Section 112 of the Proposed Rules.*

## EXHIBIT XIII

## SECTION 113: ENGINES AND TURBINES

**Q. Mr. Trent, what are your reactions to the testimony in Exhibit 32 to NMED's NOI regarding Section 113 of the Proposed Rules?**

**A.** On behalf of Kinder Morgan, I offer the following clarifying comments regarding NMED's discussion of engines and turbines in Exhibit 32 to NMED's NOI. Consistent with the below comments, following review of the technical testimony of parties to this proceeding, and, in some cases, following additional engagement with stakeholders, Kinder Morgan respectfully asks that the Board incorporate the revisions to Section 113 that are shown on the redline attached as **Exhibit XVIII**.

Availability of New Turbines Smaller Than 4,000 bhp That Meet A 25 ppm Nitrogen Oxides ("$NO_x$") Standard. NMED states that there are new turbines available on the market greater than or equal to 1,000 bhp and less than 5,000 bhp that can meet the proposed 25 ppm $NO_x$ standard without add-on controls. *See* NMED's NOI, Ex. 32, at 45.

As described in Kinder Morgan's Direct Technical Testimony, this statement is not consistent with our understanding of the current turbine market. Kinder Morgan's Direct Technical Testimony, Ex. VI, at 10. Following review of NMED's NOI, we undertook additional research regarding the sizes of turbines that are available for purchase, and the corresponding $NO_x$ emissions rates of those turbines. The results of this research are summarized in ATTACHMENT S,[4] which confirm our earlier comments on this subject.

[4] For the avoidance of doubt, each attachment is incorporated into the respective Exhibit to this Rebuttal Notice in which such attachment is referenced, and Kinder Morgan reserves the right to present all such attachments as exhibits during its hearing testimony.

As shown on ATTACHMENT S, we identified eleven turbine manufacturers. Four of the manufacturers make turbines only for power generation. These types of power generation turbines cannot be used for compression.

None of the manufacturers of turbines suitable for compression makes a turbine that is (1) below 4,000 bhp, and (2) has a 25 ppm $NO_x$ rating or lower. Of the eleven manufacturers listed on ATTACHMENT S, the three primary manufacturers for transmission compression operations are Siemens, Baker Hughes (a General Electric "GE" company), and Solar. Neither Siemens nor Baker Hughes offers any turbine below 4,000 bhp. Solar offers a Saturn 20 unit that is ISO rated at 2,000 HP, but is rated at 100 ppm of $NO_x$. The next smallest model that Solar offers is the Centaur 40, which is rated at 4,500 HP, and meets 25 ppm of $NO_x$. Solar then also offers the Centaur 45, rated at 4,700–5,000 HP depending on the version. The Centaur 45 unit can meet 15 ppm of $NO_x$.

Accordingly, Kinder Morgan stands by and reiterates its comments in Kinder Morgan's Direct Technical Testimony that turbines that (1) are suitable for compression, (2) are below 4,000 bhp, and (3) can achieve 25 ppm $NO_x$ are simply not available in today's market. For this reason, we ask that the Board implement the revisions to Table 3 shown on **Exhibit XVIII**.

<u>Turbine $NO_x$ Emissions Control From Water/Steam Injection</u>. In its NOI, NMED states that, "[t]he proposed $NO_x$ emission limits of 50 ppmvd at 15% $O_2$ for existing turbines, as set forth in Table 3 of Section 20.2.50.113, are based on the use of water or steam injection control technology." NMED's NOI, Ex. 32, at 43–44. Then, in assessing the $NO_x$ reductions and corresponding control costs for turbines less than 15,900 bhp, NMED only evaluated water or steam injection, not selective catalytic reduction ("SCR"), as the relevant control technology. *See id*. at 49–50 (discussing emission reductions), 55 (discussing costs).

At its compressor stations that are driven by turbines located in the Subject Counties (as defined in NMED's NOI), Kinder Morgan uses GE Frame 3 turbines and Solar Saturn turbines. Prior to this rulemaking, Kinder Morgan reached out to Baker Hughes to ask whether water or steam injection control technology is available for these units. A representative from Baker Hughes communicated to us that there is no $NO_x$ abatement system, including no water injection system, available for GE Frame 3 turbines. *See* ATTACHMENT T (Letter from Baker Hughes dated October 16, 2019). Likewise, as Solar explained in its July 2021 filing with the Board in this matter, water injection is not a viable control option for most Solar Saturn units. *See* ATTACHMENT U (see "Request #1"). Even where water injection of Saturn units may be theoretically viable, the corresponding carbon monoxide standard would need to be adjusted, and the feasibility and advisability of using the necessary amount of water in New Mexico's arid climate would need to be closely evaluated. *See id*. As a result, and as explained in Kinder Morgan's Direct Technical Testimony, SCR add-on technology—which is extremely expensive—would be required for Kinder Morgan's existing turbine units to achieve the proposed 50 ppm $NO_x$ standard. Without evaluation of SCR add-on technology, NMED's cost analyses with respect to emissions control technologies for turbines are incomplete.[5]

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[5] We also note that NMED may have been influenced by Pennsylvania's 25 ppm $NO_x$ standard for existing 1,000-5,000 bhp turbines set out in the GP-5 rule. However, as discussed by Solar in its July 2021 filing, important distinctions between Pennsylvania's GP-5 rule and the Proposed Rules warrant discussion. First, the GP-5 rule does not impact units constructed prior to February 1, 2013. *See* NMED's NOI, Exhibit 37, at Section M.1.(a). In Pennsylvania, only units constructed after February 1, 2013 and before August 8, 2018 are subject to the emission standards set out in the GP-5 rule, while NMED's proposal applies to all existing turbines. *See id*. at Section M.1.(b). During the GP-5 rulemaking, we understand that Solar communicated to the Pennsylvania Department of Environmental Protection ("PDEP") that the proposed $NO_x$ emission standards were not technically achievable or commercially available for turbines between 1,000 bhp and 4,000 bhp. *See* ATTACHMENT U (see "Request #1"). PDEP determined, however, that it did not need to revise the rule because no turbines between 1,000 bhp and 4,000 bhp were constructed between February 1, 2013 and August 8, 2018, and thus, no operators would be faced with this issue. *See id*. Notably, the same rationale prompted Kinder Morgan not to comment on Pennsylvania's proposed $NO_x$ standards for turbines of this size. Because the date limitation excluded Kinder Morgan's turbines in the 1,000 to 4,000 bhp range, there was no need to comment on the unachievable $NO_x$ standard.

Engine Upgrades. NMED states that "Cooper Machinery Services advertises that they offer engine upgrades that will allow engines to meet a $NO_x$ limit of 0.5 g/bhp-hr $NO_x$ for all Clark, Cooper-Bessemer, and Ingersoll Rand slow speed engine models." NMED's NOI, Ex. 32, at 37–38.

While Kinder Morgan has no reason to doubt this statement for the manufacturers listed, the list is incomplete and does not tell the whole story. There are certain older units—manufactured by companies that NMED does not list—that no engine services company has been able to upgrade to enable the engines to meet a 0.5 g/bhp-hr $NO_x$ standard. For example, the manufacturer, Worthington, makes a 1,200 hp, SLHC[6] model engine that cannot be upgraded to meet a 0.5 g/bhp-hr $NO_x$ standard. To demonstrate this point, we have attached a letter from Siemens dated December 5, 2017 explaining that emission reduction efforts for this unit would not be technically or financially feasible. *See* ATTACHMENT V. Likewise, the Worthington Mainliner engine cannot be upgraded to meet a 0.5 g/bhp-hr $NO_x$ standard. Kinder Morgan recently added emissions controls to two of these Mainliner units in Texas and Pennsylvania. In both cases, it was not possible to upgrade the engines to achieve $NO_x$ emissions of less than 5 g/bhp-hr, even with spending several million dollars on controls.

For this reason, we ask that the Board implement the revisions shown on **Exhibit XVIII** to Table 1 and add Kinder Morgan's proposed provision for retrofits that are technically impracticable or economically unreasonable.

Costs of $NO_x$ Reductions From Engines. NMED states that, "[t]he total annualized costs of adding [Low Emissions Controls] to lean-burn spark ignition engines and [non-SCR] to rich-

[6] The letters "SLHC" describe the engine unit. "S" = turbocharged, "L" = the power cylinder to compressor cylinder configuration, "H" = high compression, and "C" = compressor.

burn spark ignition engines was estimated to be $120,267,152 per year, at an average annual cost per engine of $64,452 and a cost per ton of $NO_x$ reduced of $6,717." NMED's NOI, Ex. 32, at 54.

These cost estimates are well below the costs that Kinder Morgan determined it would incur to retrofit the engines used to drive its Monument and Washington Ranch compressor stations. For the Monument station, we estimated (based on a vendor quote and accounting for other relevant costs) that low $NO_x$ emission combustion retrofits at engine Units 4 and 5 would cost a total of $6,665,866. Kinder Morgan's Direct Technical Testimony, Ex. VI, at 6. On an annualized basis, this would be equal to approximately $229,240 per unit. *Id.*, Attachment K. The corresponding cost-effectiveness of the retrofit would be approximately $72,527 per ton of $NO_x$ reduced for one unit and $125,428 per ton of $NO_x$ reduced for the other. *Id*. For the two engines that drive the Washington Ranch station, we estimated (based on information from a vendor and including other relevant costs) that the total cost of a low $NO_x$ emission combustion retrofit would be approximately $3,733,414. *Id.*, Ex. VI, at 6. This amounts to an annualized cost of approximately $128,390 per year per unit, and a cost effectiveness of $10,392 per ton of $NO_x$ reduced for one unit and $30,395 per ton of $NO_x$ reduced for the other. *Id.*, Attachment L.

I suspect that at least part of the disconnect between our cost estimates and NMED's cost estimates is that NMED has *averaged* costs across newer and older units. While retrofitting newer engines can be less expensive, the costs to retrofit a legacy engine unit are exorbitant, as demonstrated in Kinder Morgan's Direct Technical Testimony. Thus, Kinder Morgan continues to request that NMED and the Board include a clear mechanism whereby an operator may demonstrate that compliance with the $NO_x$ standards for existing engines would be technically impracticable or economically unreasonable. This proposed revision is reflected in the redline attached as **Exhibit XVIII**.

Costs of VOC Reductions From Engines. NMED states: "The annualized costs of VOC emission reductions for natural gas-fired spark-ignition engines were calculated by applying the control costs for adding oxidation catalysts to 172 uncontrolled lean burn engines. Total annualized costs for these 172 engines would be approximately $1,626,842 per year at an average annual cost per engine of $9,458 and a cost per ton of VOC reduced of $990." NMED's NOI, Ex. 32, at 55.

In our experience, the cost to install an oxidation catalyst on lean burn engines are much higher than NMED's estimates, particularly for 2-stroke lean burn units. For example, as shown on the attached estimate (which includes a vendor quote), to buy a new exhaust stack, silencer, and catalyst for a 2-stroke lean burn unit, the cost for the equipment alone would be approximately $321,742. *See* ATTACHMENT W.[7] That cost does not account for installation, foundation work, instrumentation, or other necessary items. On an annualized basis, using the Environmental Protection Agency's ("EPA's") methodology,[8] this amounts to $22,129 for the capital investment alone. *See id*. When accounting for operating and maintenance ("O&M") costs, the total annual cost would be approximately $70,115. *See id*. On a cost per ton basis, this would equal approximately $8,298 per ton of VOC reduced, which is much higher than the $990 per ton of VOC reduced as estimated by NMED.

Oxidation catalyst costs are typically lower for 4-stroke lean burn engines because those units are generally—but not always—smaller than 2-stroke lean burn engines. For one of our

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[7] Note that page 2 of the vendor quote included in ATTACHMENT W states that the price of 12 spare catalyst elements would be $63,168. This refers to 12 separate pieces of equipment that comprise one single catalyst. Note also that sensitive information has been redacted from this attachment.

[8] To arrive at the annual costs to pay for the control over time, we assumed constant payments and a constant interest rate (3.25%) over the stated period (20 years), as if the money were borrowed at that interest rate over that period of time. The formula we used included annual payments, with a loan balance of $0 after 20 years. This is consistent with general methods of amortizing costs, as described in Chapter 2 of EPA's Control Cost Manual, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

8,500 hp 4-stroke lean burn engines located in Louisiana, we paid about $150,000 total for the catalyst, housing, and stack. The catalyst alone cost about $60,000.

In sum, NMED's estimated annual cost of $9,458 per engine on average and an estimated cost effectiveness of $990 per ton of VOC reduced appears to be significantly lower than Kinder Morgan's actual anticipated costs.[9]

Costs of $NO_x$ Reductions From Turbines. NMED states that, "[t]he total annualized costs of $NO_x$ emission reductions for . . . 51 natural gas-fired turbines is approximately $13,764,391 per year at an average annual cost per turbine of $269,890 and a cost per ton of $NO_x$ reduced of $4,076." NMED's NOI, Ex. 32, at 56.

Again, these estimates are well below Kinder Morgan's cost estimates for controlling its existing turbines to meet the 50 ppm $NO_x$ standard. As explained in Kinder Morgan's Direct Technical Testimony, our turbines would require SCR and SCR is very costly. At Kinder Morgan's Rio Vista compressor station, the total cost of installing SCR on the two turbines that drive that station would be approximately $8,418,002, or about $4,200,000 per unit. Kinder Morgan's Direct Technical Testimony, Ex. VI, at 5. On an annualized basis, this is a little over $440,000 per year per unit, translating to approximately $974,508 per ton of $NO_x$ reduced for one unit and approximately $830,527 per ton of $NO_x$ reduced for the other. *Id.*, Attachment J. Likewise, adding SCR to the two turbines that drive the Caprock compressor station would cost a total of approximately $20,321,412. *Id.*, Ex. VI, at 6. This amounts to approximately $612,350 per year for one unit and $914,265 per year for the other, resulting in a cost of approximately

[9] I would also note that in its analysis of engines in New Mexico, where NMED did not know an engine type, NMED assumed the engine to be a lean burn 4-stroke engine because, in NMED's words, "that is the most common engine type for those over 1,000 bhp." NMED's NOI, Ex. 32, at 47. This is not true of Kinder Morgan's operations. We operate more 2-stroke lean burn units than 4-stroke lean burn units.

\$80,398 per ton of $NO_x$ reduced for one unit and \$54,935 per ton of $NO_x$ reduced for the other. *Id.*, Attachment I.

We suspect that the reasons that our cost estimates are so different from NMED's are two-fold. First, for turbines below 15,900 bhp, NMED only evaluated the cost of controlling $NO_x$ emissions using steam injection. NMED's NOI, Ex. 32, at 55. As a threshold matter, Kinder Morgan, a leading transmission operator in the United States that operates a significant number of turbines across its fleet, has never used water or steam injection as a control option. Further, generally speaking, costs for water or steam injection are much lower than typical costs for SCR.

Second, even for the turbines for which NMED did evaluate SCR costs, those costs are underestimated. In addition to the examples of SCR costs provided in Kinder Morgan's Direct Technical Testimony, for one of Kinder Morgan's larger units (22,000 bhp) located in Arizona, the total capital cost to install SCR would be approximately \$10,437,478, not including the cost for a new transformer, costing approximately \$650,000. *See* ATTACHMENT X (cost estimate and vendor quote for SCR installation).[10] Accounting for O&M costs, the total annual costs for this installation would be approximately \$1,430,703 and result in a cost-effectiveness of approximately \$6,623 per ton of $NO_x$ reduced, which is higher than the costs estimated by NMED. *See id*.

The high cost of SCR supports Kinder Morgan's request for the proposed provision for retrofits that are technically impracticable or economically unreasonable, shown on **Exhibit XVIII**.

[10] This cost estimate is intended to serve as an example for installing SCR on a larger turbine, and does not represent the exact costs of that retrofit if the unit were located in New Mexico. We did, however, adjust the interest rate and cost repayment period to be consistent with prior filings. Note also that sensitive information has been redacted from this attachment.

Costs of VOC Reductions From Turbines. NMED states that, "[t]he total annualized costs of VOC emission reductions for 39 natural gas-fired turbines are estimated at $3,392,186 per year, with an average annual cost per turbine of $86,979 and a cost per ton of VOC reduced of $9,608." NMED's NOI, Ex. 32, at 56.

This cost estimate also appears to be much lower than actual anticipated costs. We are in the process of installing an exhaust with an oxidation catalyst on one of our turbines in New Jersey, a Solar Titan 130 rated at 20,000 bhp. The cost for the hardware alone (*i.e.*, not including installation and other costs) for that retrofit is approximately $1,284,300. *See* ATTACHMENT Y (cost estimate).[11] On an annualized basis, this capital cost would be approximately $88,333 per year. *See id*. When accounting for O&M costs, the total annual cost would be approximately $164,472, and the overall cost-effectiveness of the retrofit would be approximately $117,714 per ton of VOC reduced. *See id*. Again, this supports our proposal to account for technical infeasibility and unreasonable costs.

**Q. Do you have any additional comments related to the version of the Proposed Rules included as Exhibit 41 to NMED's NOI?**

**A.** Yes.

First, NMED's latest version of the Proposed Rules retains the provision in Section 113 stating "in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual $NO_x$ and VOC emissions are reduced by at least ninety-five percent per year." *See* NMED's NOI, Ex. 41, Section 113.B.(2)(d). As shown on **Exhibit XVIII**, hereto, we recommend certain revisions to this provision. These revisions are needed to accommodate engines that are already

[11] This cost estimate is based on information from a vendor that is confidential.

close to the applicable emissions threshold. For such engines, the provision, as written, would fail to offer a meaningful alternative method of compliance because if such engines are controlled by 95%, they would be controlled *well below* the applicable threshold. We do not think this is NMED's intent, and ask that the Board accept our proposed changes to clarify that an operator may reduce annual hours of operation such that the annual PTE for $NO_x$ and VOC are reduced to emissions equivalent to the standards set out in Table 1.

Second, in the equation for engine load, there is no accounting for circumstances where a manufacturer's rated brake specific fuel consumption ("BSFC") is unavailable. *See id*. at Section 113.C.(3). Manufacturers' rated BSFC is sometimes unavailable, particularly for units older than the year 2000. To accommodate this reality and consistent with common industry practice, we offer a minor edit to this section in the redline attached as **Exhibit XVIII** clarifying that if the manufacturer's BSFC is unavailable, the operator may use an alternate load calculation methodology.

***Note****: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding engines and turbines.*

**ATTACHMENT S**

Summary of Turbines Available for Sale

[enclosed]

**ATTACHMENT T**

Letter from Baker Hughes dated October 16, 2019

[enclosed]

**ATTACHMENT U**

Notice of Intent to Present Technical Testimony Filed by Solar Turbines on July 27, 2021

[enclosed]

**ATTACHMENT V**

Letter from Siemens dated December 5, 2017

[enclosed]

**ATTACHMENT W**

Cost Estimate for Engine Oxidation Catalyst

[enclosed]

**ATTACHMENT X**

Cost Estimate for SCR

[enclosed]

**ATTACHMENT Y**

Cost Estimate for Turbine Oxidation Catalyst

[enclosed]

**EXHIBIT XIV**

**SECTION 114: COMPRESSOR SEALS**

**Q. Mr. Brindley, what are your reactions to the testimony in Exhibit 32 to NMED's NOI regarding Section 114 of the Proposed Rules?**

**A.** In NMED's NOI, NMED acknowledges that the VOC content of natural gas changes as the natural gas moves through the supply chain. *See, e.g.*, NMED's NOI, Ex. 32, at 59 ("[T]he fraction of VOC [in natural gas] depends on the point in the production chain the compressor is located."). This was one of the central themes from Kinder Morgan's Direct Technical Testimony, in which we explained that the quantity of VOCs in the natural gas that is moved through the transmission segment is much lower than in other segments of the supply chain. *See* Kinder Morgan's Direct Technical Testimony, Ex. V, at 1–2; Ex. VII, at 2–3; Ex. IX, at 1–2. We continue to request that, in assessing the Proposed Rules, the Board consider the unique nature of transmission segment operations. Specifically, the low-VOC content of the natural gas that Kinder Morgan transports will inform—as described in this testimony, Kinder Morgan's Direct Technical Testimony, and Kinder Morgan's Pre-Filed Non-Technical Statement filed on July 28, 2021 ("Kinder Morgan's Non-Technical Statement")—whether and how the emission standards and other requirements of the Proposed Rules *aimed at reducing VOC* should be applied to transmission operations. *See* NMED's NOI, Ex. 41, Section 6 ("The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen ($NO_x$) for oil and gas production, processing, and transmission sources.").

To illustrate this point, we have attached a spreadsheet showing the annual VOC emissions from a number of our centrifugal wet seals for the years 2018 and 2019. *See* ATTACHMENT Z. The attached spreadsheet shows that most of our centrifugal wet seals emitted 0 or close to 0 tpy of VOC, and the seal with *highest* emissions emitted approximately *0.092 tpy* of VOC. *See id*. These low emissions are consistent with the finding described in a 2018 white paper developed by the Interstate Natural Gas Association of America ("INGAA") related to improving emissions from the transmission and storage segment that "Subpart W measurement data indicates that EPA has significantly over-estimated emissions from wet seal degassing vents." *See* ATTACHMENT AA, at 8 n.44.

Related to the above, we are concerned that NMED appears to have not assessed compressor seals used in the transmission segment separately from compressor seals used in the gathering and boosting and processing segments of the natural gas supply chain. For example, NMED uses data from Tables 5-2 and 5-3 of the Environmental Protection Agency's Control Techniques Guidelines for the Oil and Natural Gas Industry (the "EPA CTG") to estimate baseline emissions from reciprocating and centrifugal compressor seals located at transmission compressor stations. *See* NMED's NOI, Ex. 32, at 65, 67. All of the data from these tables are from either gathering and boosting or from processing facilities. *See* NMED's NOI, Ex. 34, at 5-7–5-8. Neither of these categories are representative of our operations specifically because the VOC content of the natural gas that moves through our compressor stations is much lower than the VOC content of natural gas at gathering and boosting stations and processing facilities. This disconnect is further illustrated in Table 5-3's assumption that, for centrifugal compressors, "75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality." *Id*. at 5-8. This is not true of transmission compressor stations, in which 100 percent of the natural gas is pipeline quality natural gas. Thus, the methodology of applying emission factors from gathering and boosting and from processing sites to transmission compressor stations is not sound because it will result in an overestimation of emissions from such stations.

We also note that the EPA CTG cost estimates—which NMED uses to estimate costs for controlling VOC emission reductions from reciprocating compressors—cover only materials, not installation labor. *See* NMED's NOI, Ex. 32, at 68 (citing Table 5-5 of the EPA CTG); Ex. 34, at 5-13. This results in an underestimation of the costs involved in controlling VOC emissions from reciprocating compressors. Similarly, for centrifugal compressors, NMED relies on estimated—not vendor-based—costs from the Centrifugal Compressors Technical Document. *See* NMED's NOI, Ex. 32, at 69. We expect that it would be difficult to design, procure material, and construct the system needed for the costs that NMED estimates—$34,228 for one compressor. *See id*.[12]

Relatedly, the cost to replace wet seals with dry seals is very high. As noted in Kinder Morgan's Direct Technical Testimony, we recently received informal pricing information from a vendor for converting wet seals to dry seals on a Solar Saturn unit. Kinder Morgan's Direct Technical Testimony, Ex. IX, at 2. The vendor estimated that it would cost approximately $1,400,000 for this conversion. *Id*. Likewise, we previously received a quote for conversion of three Ingersoll Rand CVS-24 overhung compressors, totaling $1,561,100, and a separate quote for over $1,000,000 for conversion of a wet seal to a dry seal on a Cooper Bessemer RFBB-20 barrel style compressor.[13]

It is also important to note that wet seals are an integral component of a centrifugal compressor, and, as such, wet seal replacement with a dry seal is not a routine, simple, or

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[12] I also note that the 2018 INGAA white paper referenced earlier in this testimony indicates that installing control systems on centrifugal compressor wet seals for seal oil degassing vents—such as vapor recovery systems, thermal oxidizers, or flares—is uncommon in the transmission segment. *See* ATTACHMENT AA, at 9. That paper states that "[t]his technology is not yet a proven technology for widespread use outside a few limited situations (e.g., Alaskan operations)." *Id*. The fact that Kinder Morgan—a large and environmentally-conscious transmission company—does not have experience with this control system also indicates that it is not common practice.

[13] The variation in conversion costs is due to the different type and size of compressors involved, and whether they include single or multiple seals. Additionally, the contents of these and other vendor quotes for seal replacement are generally confidential. If it would be useful to the Board, we can attempt to obtain the consent of one or more vendors to disclose the contents of seal replacement quotes. We reserve the right to move for admission of any such quote as an exhibit before or during the hearing in this matter.

inexpensive task. Replacement of the wet seals is likely to require that the centrifugal compressor rotor be shipped back to the manufacturer or other service company to complete retooling of the compressor shaft and completion of the wet to dry seal replacement. Costs include the wet seal replacement costs, transportation costs, and customer impacts because the compressor unit will be out of service for an extended period of time to complete the replacement.

Finally, and as mentioned in Kinder Morgan's Direct Technical Testimony, there are certain potential negative implications of converting a wet seal to a dry seal. We refer the Board to Kinder Morgan's Direct Technical Testimony for a discussion of these issues. *See* Kinder Morgan's Direct Technical Testimony, Ex. IX, at 2.

In sum, the net result of NMED's testimony regarding compressor seals located at transmission compressor stations is that it *overestimates* the VOC emissions from such compressor seals and *underestimates* the costs associated with controlling those emissions. Accordingly, Kinder Morgan respectfully reiterates its request articulated in Kinder Morgan's Direct Technical Testimony that the Board either strike Section 114 from the Proposed Rules in its entirety, or, in the alternative, that the Board eliminate transmission compressor stations from the applicability of this section.

***Note****: At the hearing, Ms. Nolting and Mr. Trent will also be available to testify and answer any questions regarding compressor seals.*

**ATTACHMENT Z**

VOC Emissions From Compressor Seals

[enclosed]

**ATTACHMENT AA**

INGAA White Paper

[enclosed]

**EXHIBIT XV**

**SECTION 116: LEAK DETECTION AND REPAIR**

**Q. Ms. Nolting, what are your reactions to the testimony in Exhibit 32 to NMED's NOI regarding Section 116 of the Proposed Rules?**

**A.** In NMED's NOI, NMED states: "Under NSPS Subparts OOOO and OOOOa, many oil and gas facilities are already required to conduct [Leak Detection and Repair ("LDAR")]. ERG assumed no additional emission reductions would occur at these sources as a result of the proposed rule." NMED's NOI, Ex. 32, at 87. The fact that *no emission reduction benefits* will result from requiring facilities that conduct LDAR pursuant to federal law to comply with Section 116 underscores the necessity of Kinder Morgan's proposed revisions to Section 116.A, included in Kinder Morgan's Direct Technical Testimony and again in **Exhibit XVIII** of this filing.

Kinder Morgan also reiterates its concerns set out in Kinder Morgan's Direct Technical Testimony regarding the costs and operational challenges associated with complying with two different LDAR programs. *See* Kinder Morgan's Direct Technical Testimony, Ex. VII. To further underscore this point, we provide the following specific examples of where the Proposed Rules and federal rules diverge:

| Subject | Federal Rules | Proposed Rules | Notes |
|---|---|---|---|
| 1. Definition of component | "*Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a, | "'Component' means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or | Federal definition is broader. |

| Subject | Federal Rules | Proposed Rules | Notes |
|---|---|---|---|
| | compressors, instruments, and meters. . . . Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions." 81 Fed. Reg. 35,824, 35,934 (June 3, 2016). | methanol." NMED's NOI, Ex. 41, Section 7.H. | |
| 2. Timeline to repair leaks | Repair must be completed as soon as practicable, but not later than 30 calendar days after detection (unless delayed for the acceptable reasons set out in Subpart OOOOa). 81 Fed. Reg. 35,824, 35,906. | Repairs must be repaired within 15 or 7 days after detection. NMED's NOI, Ex. 41, Section 116.E.(2). | Different repair timelines. |
| 3. Delay of repair timeline | Delayed repairs must be repaired or replaced "during the next scheduled the next schedule compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown or within 2 years, whichever is earlier." 83 Fed. Reg. 10,628, 10,638 (Mar. 12, 2018) (amending the 2016 version of Subpart OOOOa). | Delayed repairs "must be repaired before the end of the next process unit shutdown." NMED's NOI, Ex. 41, Section 116.E.(4). | Federal rules describe different and additional circumstances that prompt repair of delayed repairs, and set an overall deadline of 2 years. |
| 4. Difficult/unsafe inspections | Permits designation of "difficult-to-monitor" and "unsafe-to-monitor" components. | Accounts for "[c]omponents that are difficult, unsafe, or inaccessible to monitor . . . ." NMED's NOI, Ex. 41, Section 116.C.(6). | Proposed Rules include "inaccessible" monitoring considerations. |
| 5. Re-survey | "Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired . . . ." 81 Fed. Reg. 35,824, 35,906. | "[T]he equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired." NMED's NOI, Ex. 41, Section 116.E.(3). | Proposed Rules require re-monitoring on a different timeline than federal rules, and regardless of whether the leak has been repaired. |
| 6. Initial monitoring | Initial monitoring survey required "within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components . . . ." 81 Fed. Reg. 35,824, 35,905. | N/A | Proposed Rules do not require initial monitoring. |

We also note the fundamental recordkeeping and reporting difference between the two programs, namely, that under federal rules, operators must report to EPA, while under the Proposed Rules, operators report to NMED. All of these differences create significant cost and operational challenges for operators who are required to comply with both programs. Such challenges are unnecessary in light of the fact that—as acknowledged by NMED—there would be no corresponding environmental or social benefit associated with such compliance.

Notably, EPA has conducted equivalency determinations between Subpart OOOOa and certain state programs, and Subpart OOOOa "[t]o reduce duplicative burdens to the industry . . . ." 85 Fed. Reg. 57,398, 57,424 (Sept. 15, 2020). The process EPA undertakes for these determinations is thorough and involves analysis of, among other factors, "the components that were included in the fugitive emissions programs, the affected facilities, the effective date(s) of the program, approved monitoring instruments, fugitive emissions definitions, monitoring frequencies, repair and resurvey timelines, and delay of repair (DOR) provisions." *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Standards at 40 CFR Part 60, Subpart OOOOa*, EPA Docket ID No. EPA-HQ-OAR-2017-0483, at 3 (Feb. 27, 2020). We would encourage the Board to heed EPA's recognition that compliance with duplicative LDAR programs is a significant burden on industry, in particular, when NMED recognizes that there are no emissions reductions benefits from the duplicative state program. Additional unnecessary process can be avoided if NMED incorporates Kinder Morgan's proposal to allow compliance with federal LDAR rules to satisfy compliance with Section 116 of the Proposed Rules.

**Q. Ms. Nolting, if the Board does not accept Kinder Morgan's proposal that compliance with federal LDAR requirements satisfies Section 116, what is Kinder Morgan's alternative proposal?**

**A.** If the Board does not accept our proposal regarding compliance with federal LDAR requirements, we respectfully offer the following alternative revisions to Section 116 related to (1) monitoring frequencies, and (2) leak repairs.

<u>Monitoring Frequencies</u>. The Proposed Rules presently require quarterly monitoring at transmission compressor stations with a facility-wide PTE less than 25 tpy VOC and monthly monitoring at transmission compressor stations with a facility-wide PTE equal to or greater than 25 tpy. *See* NMED's NOI, Ex. 41, Section 116.C.(3)(b). As shown on the redline attached as **Exhibit XVIII**, we request that the Board change these monitoring frequencies to require <u>annual monitoring</u> of all transmission compressor stations, regardless of facility-wide PTE.

As discussed in Kinder Morgan's Direct Technical Testimony, VOC emissions from fugitive sources at natural gas compressor stations are de minimis and warrant less frequent leak detection than other sites. *See* Kinder Morgan's Direct Technical Testimony, Ex. VII, at 2–3. The emissions from engines and turbines (already separately regulated under the Proposed Rules) located at transmission compressor stations would cause Kinder Morgan's facilities to exceed the facility-wide 25 tpy PTE VOC threshold set out in Section 116, subjecting such compressor stations to monthly monitoring under the current language. However, as discussed in Kinder Morgan's Direct Technical Testimony, Kinder Morgan's fugitive VOC emissions from its compressor stations—the emissions this leak detection program is designed to reduce—are typically below 1 tpy. *See id*.

Because Kinder Morgan's fugitive VOC emissions from its compressor stations are virtually nonexistent, NMED's proposed monitoring frequencies for transmission compressor stations are unnecessary and cost-ineffective. The cost to pay contractors to conduct monthly monitoring at each compressor station subject to the Proposed Rules using the Subpart OOOOa OGI method is $1,450 per monitoring event.[14] Multiplied by 12, this equals an annual cost of $17,400. Because the maximum emissions reduced at any single compressor station is roughly 1 tpy, the cost-effectiveness of monthly monitoring at transmission compressor stations would be roughly $17,400 per ton of VOC emissions reduced. This number significantly exceeds all of the established cost-effectiveness benchmarks identified in Kinder Morgan's Direct Technical Testimony. *See* Kinder Morgan's Direct Technical Testimony, Ex. VI, at 11–14.

<u>Leak Repairs</u>. The Proposed Rules require that if a leak repair is delayed (defined as a leak that cannot be repaired within 15 days of discovery or within 7 days, in the case of a leak detected using OGI), then it "must be repaired before the end of the next process unit shutdown." NMED's NOI, Ex. 41, Section 116.E.(4). While Kinder Morgan does not object to this requirement in concept, it is in tension with the realities of transmission operations. Thus, Kinder Morgan proposes a minor revision to this section in the attached redline.

Kinder Morgan routinely shuts down its operations for a variety of reasons, including, without limitation, in response to market conditions, horsepower demand, station and/or compressor unit upset, upstream issues, power losses, or natural disasters. These shutdowns typically only last for a short period of time—*e.g.*, less than one day—and it is critical that Kinder Morgan is able to bring its operations back online as quickly as possible to minimize disruption to

[14] This is based on Kinder Morgan's present actual costs for semiannual monitoring at four of its compressor stations. Note that this amount is significantly lower than two other bids that Kinder Morgan received, which were approximately $2,800 per event.

natural gas end users. Ensuring the reliability of natural gas supply is a critical public health and safety concern. Adopting a rule that may prolong these intermittent equipment or station shutdowns would inhibit transmission operators from being able to keep their systems operating reliably and meeting Federal Energy Regulatory Commission-regulated transportation obligations. These concerns are not limited to certain seasons—such as winter or summer—when natural gas demand may be higher. Rather, many natural gas transmission systems operate at high capacity year-round, and there is little redundancy in the transportation chain. Accordingly, unplanned shutdowns are simply not the appropriate time for operators to repair delayed leaks.

Furthermore, to comply with Pipeline Hazardous Materials Safety Administration regulations, natural gas compressor stations must undergo periodic scheduled shutdowns. In contrast to the unscheduled shutdowns that are inherent to the transmission sector discussed above, these scheduled maintenance shutdowns do present an appropriate opportunity for operators to undertake delayed repairs.

Thus, in order to apply the delay of repair program sensibly to the transmission sector and avoid disruptions to the sector's operations, Kinder Morgan requests that, for transmission compressor stations, the Proposed Rules be revised such that a delayed repair must be repaired during the next scheduled shutdown for maintenance or the next schedule process unit shutdown for blowdown of equipment or piping, as applicable. These revisions are shown on the redline attached as **Exhibit XVIII**.

In addition, Kinder Morgan has added a statement to Section 116, shown on **Exhibit** XVIII, making clear that if repairing a leak would result in more emissions than refraining from repairing the leak, the owner or operator is not required to undertake the repair. In some instances at transmission compressor stations, it is necessary to blowdown as many as 20 miles of pipeline to repair a leak. During the course of the blowdown process, the operator may emit to the atmosphere significantly more emissions than would be released if the leak remains because of the volume of highly compressed gas in the pipeline. For example, Kinder Morgan compared a leak rate to the blowdown that would be required for a valve replacement repair. The resulting analysis showed that the valve could leak for over 100 years before reaching the volume of gas that would be emitted during the repair. Thus, consistent with the spirit of the rule, this revision is necessary to avoid increasing rather than decreasing emissions.

***Note***: *At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions leak detection and repair.*

**EXHIBIT XVI**

**SECTION 121: PIG LAUNCHING AND RECEIVING**

**Q. Mr. Brindley, what are your reactions to the testimony in Exhibit 32 to NMED's NOI regarding Section 121?**

**A.** In NMED's NOI, NMED acknowledges that "[e]missions from pigging operations depend on factors such as . . . frequency of pigging[] and gas composition." NMED's NOI, Ex. 32, at 117. This is consistent with Kinder Morgan's testimony to date. In our Direct Technical Testimony, we pointed out that there are fewer liquids in transmission pipelines than in gathering pipelines, and, therefore, we conduct pigging operations much less frequently than others higher in the supply chain. *See* Kinder Morgan's Direct Technical Testimony, Ex. VIII. We also explained that the VOC content of natural gas in the transmission segment is much lower than in other segments of the natural gas supply chain. *See* Kinder Morgan's Direct Technical Testimony, Ex. V, at 1–2; Ex. VII, at 2–3; Ex. IX, at 1–2. Taken together, these two aspects of our operations render VOC emissions from our pigging operations insignificant. To demonstrate this point, we have attached a spreadsheet showing VOC emissions in 2020 and 2019 from pigging operations at certain of our compressor stations. *See* ATTACHMENT BB. Total annual VOC emissions in tons for each compressor station are all less than 0.04 tpy.[15] *See id*. The spreadsheet then shows this total converted to the average VOC emissions per pigging event in tons per year. *See id*. As demonstrated, no single pigging event for these compressor stations exceeds, on average, 0.01 tpy.

We also note that the portion of Exhibit 32 to NMED's NOI addressing pigging operations is largely based on gathering systems. For example, in describing pigging operations, NMED specifically describes pigging of gathering pipelines, and does not address transmission pipelines.

[15] Note also for these purposes that a compressor station may include more than one pig launching and receiving site, which explains why there are more pigging events conducted at certain compressor stations than at others.

*See* NMED's NOI, Ex. 32, at 116–117. As a result, the following statements either do not apply to pigging of transmission pipelines or paint an incomplete picture of transmission pipeline pigging operations:

- "Natural gas passing through gathering pipelines contains VOCs, as well as other impurities such as water and carbon dioxide." *Id*. at 116. The natural gas flowing through Kinder Morgan's transmission pipelines has a very low VOC content, and contains only trace amounts of impurities such as water, lubricating oil, and carbon dioxide.
- "As this gas passes through the pipeline system, any change in temperature or pressure may result in development of natural gas condensates in a liquid phase in the pipeline." *Id*. This is not true of transmission pipelines. Condensate does not develop in our transmission pipelines.
- "Emissions to the atmosphere may occur at both the pig launcher and receiver when the pipeline is opened to insert or extract the pig." *Id*. at 117. While technically true of transmission pigging operations, such emissions are minimal in the transmission context. *See* ATTACHMENT BB.
- "Emissions from pigging operations may be controlled through process modifications, through the use of add-on controls such as a flare, enclosed combustor or thermal oxidizer, or by using a vapor recovery unit (VRU)." NMED's NOI, Ex. 32, at 118. While technically accurate, it is worth noting that these types of systems are not commonly located at transmission compressor stations; rather, these systems are more commonly located at gathering systems. We have no such systems at our transmission compressor stations. As a result, to

control emissions at our pigging operations, we would need to install control equipment specifically for that use. The cost-effectiveness of this is approach would not be supported.

For the foregoing reasons, Kinder Morgan reiterates its request that, if Section 121 is retained in the Proposed Rules, the Board clarify the monitoring language to ensure that transmission pipeline pigging operations are not subjected to a monthly monitoring requirement, but rather must be monitored before and after pigging events.

***Note***: *At the hearing, Ms. Nolting and Mr. Trent will also be available to testify and answer any questions regarding pig launching and receiving operations.*

**ATTACHMENT BB**

VOC Emissions From Pigging Events

[enclosed]

# EXHIBIT XVII

## SECTION 122: PNEUMATIC CONTROLLERS AND PUMPS

**Q. Ms. Nolting, what are your reactions to the testimony in Exhibit 32 to NMED's NOI regarding Section 122 of the Proposed Rules?**

**A.** In NMED's NOI, NMED states: "In estimating costs and emission reductions for emitting pneumatic devices, it is important to note that the estimated total number of pneumatic devices at well sites/tank batteries is essentially an order of magnitude higher than the estimated total number of pneumatic devices at gathering and boosting stations, which is essentially an order of magnitude higher than the estimated total number of pneumatic devices at transmission/compression stations . . . . Thus, achieving significant reductions in VOC emissions will require replacement of emitting devices primarily at the upstream end of the production chain." NMED's NOI, Ex. 32, at 138. Put differently, the number of pneumatic devices in the transmission segment of the natural gas supply chain is roughly ***100 times*** less than the number of pneumatic controllers located at upstream sources.

Likely for this very reason, and taken together with the low VOC content of natural gas that travels through the transmission system,[16] pneumatic controllers located at transmission compressor stations ***are not subject*** to the Colorado rule regulating new and existing pneumatic controllers that was adopted earlier this year.[17] Because Section 122 is based on the Colorado rule,

[16] To illustrate, a 6 scf/hr continuous bleed pneumatic controller, assuming 5% VOC content by weight—which is higher than the typical VOC content of the natural gas in Kinder Morgan's transmission systems—would emit less than 0.1 tpy VOC.

[17] The Colorado Air Quality Control Commission ("AQCC") pneumatic controller rule "applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations)." 5 CCR 1001-9:D.III.A. As noted above, the AQCC defines "natural gas compressor station" in such a way that excludes transmission compressor stations. *See* 5 CCR 1001-9:D.I.B.19 (defining "natural gas compressor station" as "a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure ***prior to the inlet of a natural gas processing plant***") (emphasis added).

which was the result of a thorough rulemaking process, Kinder Morgan respectfully reiterates its request that the Board exclude transmission compressor stations from Section 122. *See* NMED's NOI, Ex. 32, at 128 ("The proposed rule is based on similar rules for new and existing pneumatic controllers and pneumatic pumps in Colorado Reg. 7, Sections I.K, III.C, and III.D.").

I also wish to address one additional issue relating to pneumatic devices arising from NMED's NOI. NMED states that 100% of transmission compressor stations have electrical generator engines onsite. *Id*. at 135. This is relevant, because, as NMED points out, "[a] primary determinant of the suitability of a replacement device is whether a site already has electric power." *Id*. NMED then states that "[f]or sites with electric power onsite, information suggests the least expensive option for retrofitting pneumatic devices onsite is to install instrument air." *Id*. at 136. By contrast, "[f]or sites without electric power onsite, available information indicates that the least expensive option for retrofitting pneumatic devices onsite is to install solar electric controller systems or solar-powered pumps." *Id*.

Taking these statements together, NMED's conclusion regarding pneumatic devices located at transmission compressor stations appears to be that such devices can be easily and inexpensively converted to instrument air. This is not the case for all transmission compressor stations. First, the assumption that all transmission compressor stations have electrical generators onsite is inaccurate. There is no backup power available at several of Kinder Morgan's transmission compressor stations. Second, even at Kinder Morgan's compressor stations that do have electrical generators onsite, it is likely that additional power would be needed to be able to convert the station's pneumatic devices to instrument air. Thus, at least some pneumatic devices located at Kinder Morgan's transmission compressor stations would likely need to be retrofitted by either bringing in additional power or retrofitting with the more costly solar electric controllers or solar-powered pumps.

**Q. What are your reactions to the proposal submitted by the Environmental Defense Fund, Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, 350 New Mexico, 350 Santa Fe, Center for Civil Policy, and NAVA Education Project that all natural-gas driven pneumatic controllers located at transmission compressor stations and natural gas processing plants be retrofitted to be non-emitting within six months of the effective date of the Proposed Rules?**

**A.** We oppose this proposal. It is not justified to require operators of transmission compressor stations to retrofit their pneumatic controllers on a condensed timeline and without regard to access to commercial electric power. In fact, and as noted in Kinder Morgan's Non-Technical Statement and in this Rebuttal Notice, any regulation of pneumatic controllers located transmission compressor stations would be unjustified based on the insignificant amount of VOC emissions that such controllers produce. If pneumatic controllers located at transmission compression stations remain subject to Section 122 of the Proposed Rule, then, at the very least, such controllers should be permitted a reasonable retrofitting compliance schedule.

***Note****: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding pneumatic controllers and pumps.*

**EXHIBIT XVIII**

**PROPOSED REDLINE**

[attached]

**TITLE 20 ENVIRONMENTAL PROTECTION**
**CHAPTER 2 AIR QUALITY (STATEWIDE)**
**PART 50 OIL AND GAS SECTOR — OZONE PRECURSOR POLLUTANTS**

**20.2.50.1 ISSUING AGENCY:** Environmental Improvement Board.
[20.2.50.1 NMAC — N, XX/XX/2021]

**20.2.50.2 SCOPE:** This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this ~~rule~~ Part~~or anytime thereafter~~, have ~~are causing or contributing to~~ ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part. As of the effective date, sources located in the following counties of the state are subject to this Part: Eddy, Lea, San Juan, Sandoval, and Valencia.

**A.** If, at any time after the effective date, any area any area in the state is determined by the department to have exceeded ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors, the department shall revise this rule to incorporate such areas consistent with Sections 74-1-9 and 74-2-6 NMSA. The notice of proposed rulemaking shall be published no less than one hundred and eighty (180) days before the sources in the affected area will become subject to this Part and shall include the monitoring, testing, or inspection data, and all other technical information, that demonstrate that the area or areas that is (are) the subject(s) of the proposed rulemaking exceed ninety-five percent of the national ambient air quality standard for ozone.

**(1)** The proposed rule revision shall include, in addition to the requirements of 20.1.1.301.B. NMAC .

**(a)** a list of the areas that the board proposes to become subject to this Part, and the date upon which the sources in the relevant area (or areas) will become subject to this Part; and

**(b)** proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for in each Section of this Part, for sources within the area or areas that is (are) the subject(s) of the proposed rulemaking to come into compliance with each Section of this Part.

[20.2.50.2 NMAC — N, XX/XX/2021]

**20.2.50.3 STATUTORY AUTHORITY:** Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

**20.2.50.4 DURATION:** Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

**20.2.50.5 EFFECTIVE DATE:** Month XX, ~~2021~~2022, except where a later date is specified in another Section. [20.2.50.5 NMAC - N, XX/XX/2021]

**20.2.50.6 OBJECTIVE:** The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO~~.~~) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

**[In addition to the revisions included in the following Proposed Rule section (20.2.50.7 – Definitions), where consistent with Kinder Morgan's proposed language, Kinder Morgan supports and incorporates by reference the revisions to definitions submitted by NMOGA in the redline submitted with NMOGA's Statement of Intent to Present Technical Testimony filed on July 28, 2021 ("NMOGA's Redline").]**

**20.2.50.7 DEFINITIONS:** In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

**A. "Approved instrument monitoring method"** means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

**B. "Auto-igniter"** means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

**C. "Bleed rate"** means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

**D. "Calendar year"** means a year beginning January 1 and ending December 31.

**E. "Centrifugal compressor"** means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

**F. "Closed vent system"** means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

**G. "Commencement of operation"** means for an oil and natural gas well site~~head~~, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

**H. "Component"** means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

**I. "Connector"** means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

**J. "Construction"** means fabrication, erection, or installation ~~or relocation~~ of a stationary source, ~~including~~ but does not include ~~limited to~~ relocation, replacement in-kind, temporary installations, ~~and~~or portable stationary sources.

**K. "Custody transfer"** means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

**L. "Control device"** means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

**M. "Department"** means the New Mexico environment department.

**N. "Downtime"** means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

**O. "Enclosed combustion device"** means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

**P. "Existing"** means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

[**Rationale for support for NMED proposed definition, gathering and boosting station:** KMI generally supports the definition of "gathering and boosting station," but agrees with the clarifying edits proposed by NMOGA and shown below. The key here for Kinder Morgan is to clearly distinguish between gathering and boosting and transmission.]

**Q.** **"Gathering and boosting ~~station~~site"** means a permanent combination of equipment located downstream of a well production facility that: collects or moves natural gas~~, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure~~ prior to the inlet of a natural gas processing plant or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation.

**R.** **"Glycol dehydrator"** means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

**S.** **"Hydrocarbon liquid"** means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

**T.** **"Liquid unloading"** means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

**U.** **"Liquid transfer"** means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

**V.** **"Local distribution company custody transfer station"** means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

[**Rationale for striking proposed definition, natural gas compressor station:** The term, "natural gas compressor station" includes both "gathering and boosting stations" and "transmission compressor stations." It is not appropriate to discuss these operations as the same type, as they exist at entirely different points along the natural gas supply chain. With refined definitions of "gathering and boosting station" and "transmission compressor station," a separate and effectively combined definition of "natural gas compressor station" is not necessary, and any such combined definition is bound to create confusion and conflict. For example, in each applicability section of the proposed rules, NMED lists both "gathering and boosting stations" and "natural gas compressor stations," but deletes "transmission compressor stations." This creates at least some confusion in that the gathering and boosting segment is specifically identified, but transmission is not independently identified (like gathering and boosting) apart from the general definition of natural gas compressor stations referencing transmission compressor stations. It seems unnecessary in this and other instances to refer to "natural gas compressor stations" if "transmission compressor station" is the intended term.

Another specific example of conflict arises in the context of NMED's proposed Section 122 – Pneumatics. Table 1 outlines the cohorts for total historic percentage of non-emitting controllers, which dictates the required percentages of non-emitting controllers year-over-year. Table 1 applies to well sites, tank batteries, and gathering and boosting stations. Table 2 outlines different cohorts with different required percentages for non-emitting controllers. Table 2 applies to natural gas compressor stations and gas processing plants. Under the NMED's current definitions, a compressor station in the gathering and boosting segment is both a "gathering and boosting station" and "natural gas compressor station." So, should such a facility comply with Table 1 or Table 2 for Section 122? While we refer NMED to this rule section by way of example only, for the avoidance of doubt, Kinder Morgan re-iterates that we support NMOGA's comments on Section 122 to revise the proposed rule to better conform with the Department's intent to model Colorado's rule, including excluding transmission compressor stations from rule application.]

~~**W.** **"Natural gas compressor station"** means a facility, including all equipment and compressors, designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. Natural gas compressor stations include transmission compressor stations.~~

**~~X.~~W.** **"Natural gas-fired heater"** means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

**~~Y.~~X.** **"Natural gas processing plant"** means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

**~~Z.~~Y.** **"New"** means constructed or reconstructed on or after the effective date of this Part.

**~~AA.~~Z.** **"Operator"** means the person or persons responsible for the overall operation of a stationary source.

~~BB.~~AA. **"Optical gas imaging (OGI)"** means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

~~CC.~~BB. **"Owner"** means the person or persons who own a stationary source or part of a stationary source.

~~DD.~~CC. **"Permanent pit"** means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

~~EE.~~DD. **"Pneumatic controller"** means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

~~FF.~~EE. **"Pneumatic diaphragm pump"** means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

~~GG.~~FF. **"Potential to emit (PTE)"** means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

~~HH.~~GG. **"Produced water"** means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

~~II.~~HH. **"Produced water management unit"** means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

~~JJ.~~II. **"Qualified Professional Engineer"** means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

~~KK.~~JJ. **"Reciprocating compressor"** means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

~~LL.~~KK. **"Reconstruction"** means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

~~MM.~~LL. **"Recycling facility"** means a stationary or portable facility used exclusively for the treatment, reuse, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

~~NN.~~MM. **"Responsible official"** means one of the following:

**(1)** for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

**(2)** for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

~~OO.~~NN. **"Small business facility"** means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

~~PP.~~OO. **"Startup"** means the setting into operation of air pollution control equipment or process equipment.

~~QQ.~~PP. **"Stationary Source"** or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

~~RR.~~QQ. **"Storage vessel"** means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

[**Rationale for proposed revisions, transmission compressor station**: We agree with NMED that a definition of "transmission compressor station," separate from the definition of "gathering and boosting station," is appropriate, and we thank the NMED for including this new definition. First, as noted above, when intending to apply a rule section to a transmission compressor station, the rule should refer to "transmission compressor station" and not "natural gas compressor station," the latter of which we are proposing to delete. We have made this revision throughout this redline.

Second, we have proposed a few clarifying edits to the definition of "transmission compressor station." We think it is important to refer to "pipeline quality" natural gas, as this is one of the key differentiating features between gathering and boosting and transmission. We've revised natural gas processing "facilities" to "plants" as that is the defined term in these proposed rules. Transmission should be referred to as "through" a pipeline. Delivery from transmission operations will go to the local distribution company custody transfer station (an NMED defined term, which may be a pipeline or may be a facility), into underground storage, or to other industrial users. Finally, it is not necessary or appropriate to enumerate different types of equipment that may be located at a transmission compressor station as "all equipment" is already included. Additionally, when read together with related definitions, listing specific equipment may imply that the listed types of equipment are at transmission compressor stations and are not at gathering and boosting stations or natural gas processing plants, which is not accurate.]

~~SS.~~**RR.** **"Transmission Compressor Station"** means a facility, including all equipment and compressors, that moves pipeline quality natural gas at ~~elevated~~ increased pressure from a well site~~s~~ or natural gas processing ~~facilities~~ plant ~~in~~ through a transmission pipeline~~s~~ for ultimate delivery to the local ~~natural gas~~ distribution company custody transfer station, ~~pipelines or~~ into underground storage, or to other industrial end users. ~~Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids~~

~~TT.~~SS. **"Well workover"** means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

~~UU.~~TT. **"Well site"** means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A well site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.
[20.2.50.7 NMAC - N, XX/XX/2021]

**20.2.50.8 SEVERABILITY:** If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.50.8 NMAC - N, XX/XX/2021]

**20.2.50.9 CONSTRUCTION:** This Part shall be liberally construed to carry out its purpose. [20.2.50.9 NMAC - N, XX/XX/2021]

**20.2.50.10 SAVINGS CLAUSE:** Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.
[20.2.50.10 NMAC - N, XX/XX/2021]

**20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS:** Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2021]

**20.2.50.12 DOCUMENTS:** Documents incorporated and cited in this Part may be viewed at the New

Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

**20.2.23.13-20.2.23.110 [RESERVED]**

**20.2.50.111 APPLICABILITY:**

**A.** This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at well sites, tank batteries, gathering and boosting ~~stations~~sites, natural gas processing plants, and ~~natural gas~~transmission compressor stations, up to the point of, but not including, the local distribution company custody transfer station.

**B.** In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer. The requirements of this part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

**C.** An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

**D.** Oil refinery and transmission pipelines are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

**20.2.50.112 GENERAL PROVISIONS:**

**[Kinder Morgan supports and incorporates by reference the proposed revisions to 20.2.50.112 (General Provisions) submitted in NMOGA's Redline.]**

* * *

**20.2.50.113 ENGINES AND TURBINES:**

**A. Applicability:** Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting ~~stations~~sites, natural gas processing plants, and ~~natural natural gas~~transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

**B. Emission standards:**

**(1)** The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

**(2)** The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all ~~existing~~ subject engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

**(a)** by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

**(b)** by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

**(c)** by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

**[The following clarification in subpart (d) is an important revision. If not revised, this would require an engine that may be *right above* the applicable threshold to have to control by 95%, which would mean they may be required to control well below the applicable threshold. We do not think that is the intent, and we ask that the NMED and Board accept the following change for clarity.]**

**(d)** in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Section B of 20.5.50.113 or by at least ninety-five percent per year.

**[As discussed at length in Kinder Morgan's Notices of Intent to present direct and rebuttal technical testimony, there will be circumstances when it is not technically practicable or economically reasonable to retrofit an existing engine to achieve the prescribed standards. In those circumstances, the rules must afford the operator an opportunity to make a demonstration to NMED that, based on the best information available for determining technically practicable retrofit technology and control efficiency, achieving the standard is impracticable or unreasonable and an exception is necessary.]**

**(e)** Owners or operators of an existing natural gas-fired spark-ignition engine are not required to comply with the emissions standards specified in table 1 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impracticable or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticability or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (2) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

**[NMED should be afforded the discretion to grant a variance to the timetable set forth in Paragraph (2) of Subsection B of 20.2.50.113 NMAC, as appropriate and for good cause shown.]**

**(f)** Any of the effective dates for the emissions standards set forth in Paragraph (2) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED~~,~~ OR RECONSTRUCTED~~, OR INSTALLED~~ BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

**[Kinder Morgan supports the following revisions to the engine thresholds as proposed in NMOGA's Redline, with a revision to the CO thresholds.]**

| Engine Type | Rated bhp | $NO_x$ | CO | NMNEHC (as propane) |
|---|---|---|---|---|
| 2 Stroke Lean-burn | >1,000 | 3~~0~~.0~~50~~ g/bhp-hr | 0.60 g/bhp-hr~~47 ppmvd @ 15% $O_2$ or 93%~~ | 0.70 g/bhp-hr |
| 4 Stroke Lean-burn | >1,000 | 2.0 g/bhp-hr | 0.60 g/bhp-hr | 0.70 g/bhp-hr |
| Rich-burn | >1,000 | 0.50 g/bhp-hr | 0.60 g/bhp-hr | 0.70 g/bhp-hr |

**(3)** The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

**[Kinder Morgan supports the following revisions to the engine thresholds as proposed in NMOGA's Redline,**

**with a few revisions.]**

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED~~,~~ OR RECONSTRUCTED~~, OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

| Engine Type | Rated bhp | $NO_x$ | CO | NMNEHC (as propane) |
|---|---|---|---|---|
| ~~Lean-burn~~ | ~~>500 - <1,000~~ | ~~0.50 g/bhp-hr~~ | ~~0.60 g/bhp-hr~~ | ~~0.70 g/bhp-hr~~ |
| 4-Stroke Lean-burn | >~~1,000~~500 and <1875 | 0.5~~0.30~~ g/bhp-hr ~~uncontrolled or 0.05 g/bhp-hr with control~~ | 0.60 g/bhp-hr | 0.70 g/bhp-hr |
| 4-Stroke Rich-burn | >500 | 0.5~~0.50~~ g/bhp-hr | 0.60 g/bhp-hr | 0.70 g/bhp-hr |
| 4-Stroke Lean-burn | ≥1875 | 0.3 g/bhp-hr | 0.60 g/bhp-hr | 0.70 g/bhp-hr |

**(4)** The owner or operator of a natural gas-fired spark ignition engine with NO. emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

**(5)** The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

**(a)** a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO. emissions to not more than nine g/bhp-hr upon startup.

**(b)** a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

**(6)** The owner or operator of a portable or stationary compression ignition engine with NO. emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

**(7)** The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

**[As discussed in Kinder Morgan's Notices of Intent to present direct and rebuttal technical testimony, a reasonable schedule to achieve the proposed emissions thresholds is necessary for turbines. Modification is equally as complex, costly, and time-intensive, and Kinder Morgan operates approximately the same number of turbines as engines that would be subject to the proposed rules.]**

**(a)** The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to this Part 50 by July 1, 2022, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC except as approved through an alternative Compliance Plan per 20.2.50.113 B.9 as follows:

(i) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meets the emission standards.

(iii) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meets the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(v) Owners or operators of an existing natural gas-fired combustion turbine are not required to comply with the emissions standards specified in table 3 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impracticable or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticability or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(vi) Any of the effective dates for the emissions standards set forth in Paragraph (7) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

**[Following review of other parties' Notices of Intent to Present Technical Testimony, and engagement with stakeholders, Kinder Morgan supports the following reasonable revisions to the proposed emissions standards applicable to both new and existing stationary combustion turbines.]**

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

| | | | |
|---|---|---|---|
| **For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of of Subsection B of 20.2.50.113 NMAC ~~two years from the effective date of this Part~~:** | | | |
| Turbine Rating (bhp) | $NO_x$ (ppmvd @15% $O_2$) | CO (ppmvd @ 15% $O_2$) | NMNEHC (as propane, ppmvd @15% $O_2$) |
| ≥1,000 and <4,000~~5,000~~ | ~~50~~150 | 50 | 9 |
| ≥4,000~~5,000~~ and <15,000 | 50 | 50 | 9 |
| ≥15,000 | 50 | 50 or 93% reduction | 5 or 50% reduction |
| **For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:** | | | |
| Turbine Rating (bhp) | $NO_x$ (ppmvd @15% $O_2$) | CO (ppmvd @ 15% $O_2$) | NMNEHC (as propane, ppmvd @15% $O_2$) |
| ≥1,000 and <4,000~~5,000~~ | ~~25~~100 | 25 | 9 |
| ≥4,000~~5,000~~ and <15,900 | 15 | 10 | 9 |
| ≥15,900 | 9.0 Uncontrolled or 2.0 with Control | 10 Uncontrolled or 1.8 with Control | 5 |

**(8)** The owner or operator of a stationary natural gas-fired combustion turbine with NO. emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

**(9)** The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

**[As discussed in Kinder Morgan's Notice of Intent to Present Technical Testimony, the following revision is intended to clarify the use of the term "emergency engine" and to align the same with federal definitions.]**

**(10)** The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~that is operated less than 100 hours per year~~ is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

**C. Monitoring requirements:**

**[Where the manufacturer recommended maintenance schedule and practices are outdated or otherwise inappropriate, the operator should be able to use good engineering and maintenance practices. As discussed in Kinder Morgan's Notice of Intent to Present Technical Testimony, this approach is consistent with Colorado's Regulation No. 7.]**

**(1)** Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine subject to an emission standard in Subsection B of 20.2.50.113 shall be consistent with ~~meet~~ the minimum manufacturer recommended maintenance schedule or good engineering and maintenance practices. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

**(a)** routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

**(b)** unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

**(2)** Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to good engineering and maintenance practices or manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

**(3)** For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for $NO_R$, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

**[In some situations, the manufacturer's rated BSFC is not available, in particular, for most units older than the year 2000. The following minor edit is intended to account for those circumstances and allow for an alternative calculation. BSFC is regularly determined through current engineering practices and does not rely on manufacturer's rate.]**

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption. If the manufacturer's rated BSFC is not available, an operator may use an alternate load calculation methodology based on available data.

**(a)** emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

**(b)** emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

**(c)** the default time period for a test run shall be at least 20 minutes.

**(d)** an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

**(e)** during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

**(f)** stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

**(g)** upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

**(h)** emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

**(4)** The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

**(5)** An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated for less than 100 hours per year~~ shall monitor the hours of operation by a non-resettable hour meter.

**(6)** An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

**(7)** Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

**D. Recordkeeping requirements:**

**(1)** The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

**(a)** the make, model, serial number, and EMT for the engine or turbine;

**(b)** a copy of the maintenance and repair schedule for the engine, turbine, or control device as recommended by the manufacturer ~~recommended maintenance and repair schedule~~or as developed consistent with good engineering and maintenance practices;

**(c)** all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

**(i)** the date and time of an inspection, maintenance or repair;

**(ii)** the date a subsequent analysis was performed (if applicable);

**(iii)** the name of the personnel conducting the inspection, maintenance or

**(iv)** repair;

**(v)** a description of the physical condition of the equipment as found during the inspection;

**(vi)** a description of maintenance or repair activity conducted; and

**(vii)** the results of the inspection and any required corrective actions.

**(2)** The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine. The records shall include:

**(a)** the make, model, serial number, and EMT for the tested engine or turbine;

**(b)** the date and time of sampling or measurements;

**(c)** the date analyses were performed;

**(d)** the name of the personnel and the qualified entity that performed the analyses;

**(e)** the analytical or test methods used;

**(f)** the results of analyses or tests;

**(g)** for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

**(h)** operating conditions at the time of sampling or measurement.

**(3)** The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated less than 100 hours per year~~ shall record the total annual hours of operation as recorded by the non-resettable hour meter.

**(4)** The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

**(5)** An owner or operator claiming an exemption under Paragraph 2(e) or Paragraph (7)(a)(v) of Subsection B of 20.2.50.113 must maintain records for each engine or turbine, as applicable, demonstrating that the exemption applies.

**(6)** An owner operator that received an extension of the effective dates for an emissions standards set forth in Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC must maintain records of the extension for good cause shown.

**E. Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.113 NM—C - N, XX/XX/2021]

**20.2.50.114 COMPRESSOR SEALS:**

**[For the reasons articulated in Kinder Morgan's Notices of Intent to present direct and rebuttal technical testimony, we request the Board eliminate transmission compressor stations from the applicability of this section.]**

**A. Applicability:**

**(1)** Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting ~~stations~~sites, or natural gas processing plants ~~, or natural gas compressor stations~~ are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well sites are not subject to the requirements of 20.2.50.114 NMAC.

**[Remainder of section redacted to streamline redline.]**

* * *

**20.2.50.115 CONTROL DEVICES:**

**[In addition to the revisions included in the following Proposed Rule section (20.2.50.115 – Control Devices), Kinder Morgan supports and incorporates by reference the revisions submitted in NMOGA's Redline.]**

**A. Applicability:** These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

**B. General requirements:**

**(1)** Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

**(2)** Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or $NO_R$.

**(3)** The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

**[The following minor revision is necessary to avoid the unintended outcome that operators would be required to visually inspect the internal components of a catalyst.]**

**(4)** The owner or operator shall inspect visually, or consistent with federally-approved inspection methods, control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

**[Remainder of section redacted to streamline redline.]**

* * *

**20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:**

**[Kinder Morgan requests the Board revise the Proposed Rules to state that compliance with NSPS OOOO, OOOOa, or another NSPS subpart, as each may be revised, satisfies the requirements of Section 116. This provision would avoid the unnecessary result of competing LDAR programs at the state and federal level (as discussed in Kinder Morgan's Notices of Intent to present direct and rebuttal technical testimony), in particular, where NMED recognizes in its Notice of Intent to Present Technical Testimony that no additional emissions reduction benefits will be achieved by those operators/facilities already employing the federal LDAR programs.**

**In the alternative, Kinder Morgan requests the Board adopt an annual leak detection frequency for transmission compressor stations given that the fugitive VOC emissions from Kinder Morgan's transmission compressor stations are typically less than 1 tpy VOC emissions.]**

**A. Applicability:** Well sites, tank batteries, gathering and boosting ~~stations~~sites, gas processing plants, ~~natural gas~~transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility's PTE and in determining the monitoring frequency requirements of this Section. Equipment leak and fugitive emissions monitoring required by New Source Performance Standards, including but not limited to Subpart OOOO and Subpart OOOOa, 40 C.F.R. Part 60, as each may be revised, may be used to satisfy the requirements of this 20.2.50.116 NMAC.

**B. Emission standards:** The owner or operator of oil and gas production and processing equipment located at well sites, tank batteries, gathering and boosting ~~stations~~sites, gas processing plants, or ~~natural gas~~transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

**C. ~~Default~~ Monitoring, inspection, or testing requirements:** Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

**(1)** The owner or operator of a ~~facility~~ well site or tank battery with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

**(a)** conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

**(b)** conduct an audio inspection for pressure leaks and liquid leaks;

**(c)** conduct an olfactory inspection for unusual or strong odors;

**(d)** any positive detection during the AVO inspection shall be considered a leak; and

**(e)** a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

**(2)** The owner or operator of a ~~facility~~ well site or tank battery with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

**(3)** The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

**(a)** for well sites or tank battery facilities:

**(i)** annually at facilities with a PTE less than two tpy VOC;

**(ii)** semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

**(iii)** quarterly at facilities with a PTE equal to or greater than five tpy VOC.

**(b)** for gathering and boosting ~~stations~~ sites and ~~,~~ gas processing plants~~, and natural gas compressor stations~~:

**(i)** quarterly at facilities with a PTE less than 25 tpy VOC; and

**(ii)** monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(c) for transmission compressor stations:

(i) annually at all transmission compressor stations.

**(4)** Inspections using U.S. EPA method 21 shall meet the following requirements:

**(a)** the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

**(b)** the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane; and

**(c)** a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

**(5)** Inspections using OGI shall meet the following requirements:

**(a)** the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

**(b)** a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

**(6)** Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

**(a)** difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

**(b)** unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

**(c)** inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

**D.** **Alternative equipment leak monitoring plans:** As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

**(1)** An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

**(a)** the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

**(b)** the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

**(c)** upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

**(2)** An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

**(a)** the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

**(b)** the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

**(c)** upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.0 NMAC within 15 days.

**[If the federal compatibility language is not adopted and transmission compressor stations are required to inspect for leaks annually, it is imperative that the delay of repair appropriately account for the unique operations at transmission compressor stations to avoid implementation concerns and unintended (and unnecessary) emissions in the event repair of a component requires blowdown of the equipment or piping. First, transmission compressor stations may shutdown intermittently in response to market conditions. These shutdowns are not always scheduled, and even if they are scheduled, they may be scheduled for *very* brief periods of time whereby maintenance activities are not reasonable. Thus, a revision is needed to be clear that the shutdown is <u>scheduled</u> and <u>for maintenance.</u> Furthermore, at transmission compressor stations, in some instances, in order to repair a leak an operator may be required to blowdown several pieces of equipment or as much as 20 miles of pipeline. In so doing, the operator may emit to atmosphere significantly more emissions in proportion to the leak. For example, in one particular instance, Kinder Morgan evaluated the leak rate vs the blowdown where delay of repair was triggered. The repair would have required Kinder Morgan to replace the valve. Kinder Morgan estimated the valve could leak for over 100 years before emitting the same volume that would be emitted to atmosphere by repairing it, which required blowdown of a significant length of pipeline. Thus, the following revision is necessary in order to limit emissions in the spirit of this set of Proposed Rules.**

**The following approach is also consistent with NSPS OOOOa, 40 C.F.R. § 60.5397a(h)(3).]**

**E.** **Repair requirements:** For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

**(1)** the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

**(2)** leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

**(3)** the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

**(4)** if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next <u>scheduled</u> process unit shutdown <u>for maintenance, or the next scheduled process unit shutdown for blowdown of equipment or piping, as applicable, or within two years, whichever is earliest</u>. <u>For transmission compressor stations, the owner or operator is not required to repair the leak if the equipment leak, based on continuous leakage during the three year period since discovery, is less than the volume of gas required to</u>

be vented to atmosphere in order to make the repair.

**F. Recordkeeping requirements:**

**(1)** The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

**(a)** facility location;

**(b)** date of inspection;

**(c)** monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

**(d)** name of the personnel performing the inspection;

**(e)** a description of any leak requiring repair or a note that no leak was found; and

**(f)** whether a visible flag was placed on the leak or not;

**(2)** The owner or operator shall keep the following record for any leak that is detected:

**(a)** the date the leak is detected;

**(b)** the date of attempt to repair;

**(c)** for a leak with a designation of "repair delayed" the following shall be recorded:

**(i)** reason for delay if a leak is not repaired within the required number of days after discovery;

**(ii)** signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;

**(d)** date of successful leak repair;

**(e)** date the leak was monitored after repair and the results of the monitoring; and

**(f)** a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

**(3)** For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

**(4)** The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

**G. Reporting requirements:**

**(1)** The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

**(2)** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

**20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:**

* * *

**20.2.50.118 GLYCOL DEHYDRATORS:**

**A. Applicability:** Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well sites, tank batteries, gathering and boosting ~~stations~~sites, natural gas processing plants, and ~~natural gas~~transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

* * *

**20.2.50.119 HEATERS:**

**A. Applicability:** Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting ~~stations~~sites, natural gas processing plants, and ~~natural gas~~transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

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**20.2.50.120 HYDROCARBON LIQUID TRANSFERS:**

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**20.2.50.121 PIG LAUNCHING AND RECEIVING:**

**[In addition to the revisions included in the following Proposed Rule section (20.2.50.121 – Pig Launching and Receiving, Kinder Morgan supports and incorporates by reference the revisions submitted in NMOGA's Redline.]**

**A. Applicability:** Pipeline pig launching and receiving operations located within or outside of the property boundary of well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations are subject to the requirements of 20.2.50.121 NMAC.

**B. Emission standards:**

**(1)** Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

**(2)** The owner or operator conducting the pig launching and receiving operation shall:

**(a)** employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

**(b)** employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

**(c)** recover and dispose of receiver liquid in a manner that ~~prevents~~ minimizes emissions to the atmosphere; and

**(d)** ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

**(3)** The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

**(4)** An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

**C. Monitoring requirements:**

**(1)** The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

**(2)** The owner or operator of an affected pig launching ~~and~~ or receiving ~~operations~~ site shall inspect the equipment for ~~a~~ leaks either AVO, using RM 21 or OGI on either, as applicable:

**(a)** a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

**(b)** immediately prior to ~~before~~ the commencement and immediately after the conclusion of the pig launching or receiving operation~~, and according to the requirements in 20.2.50.116 NMAC~~.

**(3)** The monitoring procedures shall be performed using the methodologies outlined in Paragraphs (2) through (4)) of Subsection (C) of 20.2.50.116 NMAC as applicable, and at the frequency outlined in Paragraph (2) of Subsection (C) of 20.2.50.121.

~~**(3)**~~**(4)** An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

~~**(3)** The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.~~

**D. Recordkeeping requirements:**

**(1)** The owner or operator of pig launching and receiving operations shall maintain a record of the following:

**(a)** the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

**(b)** the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

**(c)** the type of control device and its location, make, and model.

**(2)** The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

**E. Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

**20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:**

**[Kinder Morgan supports and incorporates by reference the revisions to 20.2.50.122 NMAC submitted in NMOGA's Redline. In the alternative, and at the least, the following revisions should be made to conform to the revised definitions proposed herein.]**

**A. Applicability:** Natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting ~~stations~~sites, natural gas processing plants, and ~~natural gas~~ transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

**B. Emission standards:**

**(1)** A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

**(2)** An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

**(3)** An existing natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 - WELL SITES, TANK BATTERIES, GATHERING AND BOOSTING ~~STATIONS~~SITES

| Total Historic Percentage of Non-Emitting Controllers | Total Required Percentage of Non-Emitting Controllers by January 1, 2024 | Total Required Percentage of Non-Emitting Controllers by January 1, 2027 | Total Required Percentage of Non-Emitting Controllers by January 1, 2030 |
|---|---|---|---|
| > 75 % | 80% | 85% | 90% |
| > 60-75 % | 80% | 85% | 90% |
| > 40-60 % | 65% | 70% | 80% |
| > 20-40 % | 45% | 70% | 80% |
| 0-20 % | 25% | 65% | 80% |

Table 2 - ~~NATURAL GAS~~ TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

| Total Historic Percentage of Non-Emitting Controllers | Total Required Percentage of Non-Emitting Controllers by January 1, 2024 | Total Required Percentage of Non-Emitting Controllers by January 1, 2027 | Total Required Percentage of Non-Emitting Controllers by January 1, 2030 |
|---|---|---|---|
| > 75 % | 80% | 95% | 98% |
| > 60-75 % | 80% | 95% | 98% |
| > 40-60 % | 65% | 95% | 98% |
| > 20-40 % | 50% | 95% | 98% |
| 0-20 % | 35% | 95% | 98% |

**(4)** Standards for natural gas-driven pneumatic controllers.

**(a)** new pneumatic controllers shall have an emission rate of zero.

**(b)** existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.

**(c)** existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

**(i)** by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

**(ii)** determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

**(iii)** determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

**(iv)** based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

**(v)** if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator is not subject to the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

**(vi)** if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

**(d)** a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

**(5)** Standards for natural gas-driven pneumatic pumps.

**(a)** pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

**(b)** pneumatic pumps located at a well sites, tank batteries, gathering and boosting ~~stations~~sites, or ~~natural gas~~transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

**(c)** owners and operators of pneumatic pumps located at well sites, tank batteries, gathering and boosting ~~stations~~sites, or ~~natural gas~~transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

**(6)** The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

**C. Monitoring requirements:**

**(1)** Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

**(2)** The owner or operator of a pneumatic controller subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

**(3)** The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

**(4)** The EMT shall be linked to a database that contains the following:

**(a)** pneumatic controller identification number;
**(b)** type of controller (continuous or intermittent);
**(c)** if continuous, design continuous bleed rate in standard cubic feet per hour;
**(d)** if intermittent, bleed volume per intermittent bleed in standard cubic feet; and
**(e)** design annual bleed in standard cubic feet per year.

**(5)** The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

**(6)** The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

**D. Recordkeeping requirements:**

**(1)** Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

**(2)** The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

**(3)** The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

**(4)** The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

**(5)** The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

**(a)** pneumatic controller identification number;
**(b)** inspection dates;
**(c)** name of the personnel conducting the inspection;
**(d)** AVO inspection result;
**(e)** AVO level discrepancy in continuous or intermittent bleed rate;
**(f)** maintenance date and maintenance activity; and
**(g)** a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

**(6)** The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC.

**(7)** The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

**(a)** for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

**(b)** a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

**(c)** records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

**(8)** The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

**E. Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

**20.2.50.123 STORAGE VESSELS**

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**20.2.50.124 WELL WORKOVERS**

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**20.2.50.125 SMALL BUSINESS FACILITIES**

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**20.2.50.126 PRODUCED WATER MANAGEMENT UNITS**

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**20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION**

**[Kinder Morgan supports and incorporates by reference the proposed revisions to 20.2.50.127 NMAC submitted in NMOGA's Redline (as revised on August 30, 2021).]**

**HISTORY OF 20.2.50 NMAC: [RESERVED]**

## CERTIFICATE OF SERVICE

I hereby certify that on September 7, 2021, a true and correct copy of the foregoing **NOTICE OF INTENT TO PRESENT REBUTTAL TECHNICAL TESTIMONY OF KINDER MORGAN, INC. AND ITS SUBSIDIARIES AND AFFILIATES, EL PASO NATURAL GAS COMPANY, L.L.C., TRANSCOLORADO GAS TRANSMISSION CO., LLC, AND NATURAL GAS PIPELINE COMPANY OF AMERICA, LLC** was filed with Board Administrator, Pamela Jones, via electronic mail and served via electronic mail to the following:

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*_/s/ Ana Maria Gutiérrez_*
Ana Maria Gutiérrez